Preliminary
Determination of Compliance

Russell City Energy Center

Bay Area Air Quality Management District
Application 2896

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I Introduction

This is the Preliminary Determination of Compliance (PDOC) for the Russell City Energy Center (RCEC), a natural-gas fired, combined cycle merchant power plant proposed by Calpine Corporation and Bechtel Holdings, Inc. (Calpine). Full load output under expected operating conditions is a nominal 600 net MW to a peak of 675 net MW. The power plant is located in the City of Hayward, 1.24 miles east of Johnson Landing on the southeastern shore of the San Francisco Bay. The RCEC will consist of two natural gas fired Seimens Westinghouse 501F combustion turbine generators (CTGs), one steam turbine generator (STG) and associated equipment, two supplementally fired heat recovery steam generators (HRSGs), a 10-cell wet cooling tower, a natural gas fired 660 kW emergency generator, and a 400 hp diesel fired pump engine.

A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Preliminary Determination of Compliance (PDOC) document for the RCEC. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #2896. Section IV, Permit Conditions, serves as the proposed PSD permit. The PDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review Regulation 2, Rule 2. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

Pursuant to Regulation 2, Rule 3, Section 404, this PDOC is subject to the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

B. Project Description

1. Process Equipment

The applicant is proposing a combined-cycle cogeneration facility with a nominal net electrical output of 600 MW and peak of 675 net MW. The RCEC will consist of the following new permitted equipment:

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 1979.4 MMBtu/hr maximum rated capacity, natural gas fired only; Abated by A-1 Selective Catalytic Reduction (SCR) System.

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System.

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 1979.4 MMBtu/hr maximum rated capacity, natural gas fired only; Abated by A-2 Selective Catalytic Reduction (SCR) System.

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-2 Selective Catalytic Reduction (SCR) System.

S-5 Cooling Tower, Ten Cells, 135000 gallons per minute

S-6 Emergency Generator, with Caterpillar G3512-90-LE natural gas-fired engine, 660 kW, 6.44 MMBtu/hr input

S-7 Diesel Engine, Cummins 6CTA8.3-F3, 400 hp, 2.11 MMBtu/hr input

As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 200 MW and the steam produced by both heat recovery steam generators (HRSGs) will feed to a single steam turbine generator with a nominal electrical output of 235 MW.

2. Equipment Operating Scenarios

As a merchant power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

Base Load: Maximum continuous output with duct firing and power augmentation steam injection during high ambient temperature conditions

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

Partial Shutdown: Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during period of low overall demand such as late evening and early morning hours

Full Shutdown: May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

HRSG Duct Burner Firing with Steam Injection Power Augmentation:

Under peak demand situations and high ambient temperatures, steam may be injected into the gas turbine combustors to lower the flame temperature and allow increased fuel use rate, which results in increased mass flow through the gas turbine thereby increasing maximum electrical output.

The following projected operating scenario for each turbine (@ 60°F) was utilized to estimate maximum annual air pollutant emissions from the new gas turbines and HRSGs.

- 6,844 hours per year of turbine operation without duct burner firing
- 1,500 hours per year of turbine operation with duct burner firing and steam injection power augmentation
- 260 hours of gas turbine hot start-ups per year
- 156 hours of gas turbine cold start-ups per year

3. Air Pollution Control Strategies and Equipment

The proposed RCEC includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NO_x), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The gas turbines and HRSG duct burners each trigger BACT for NO_x emissions. The gas turbines will be equipped with dry low-NO_x (DLN) combustors, which minimize NO_x emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. The HRSGs will be equipped with low-NO_x duct burners, which are designed to minimize NO_x emissions. In addition, the combined NO_x emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level NO_x emission limit of 2.5 ppmvd @ 15% O_2 (one hour average).

b. Dry Low-NO_x (DLN) Combustors to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-NO_x combustors, which operate on a lean fuel mixture that minimizes CO emissions. The HRSGs will be equipped with low-NO_x duct burners, which are also designed to minimize CO emissions. Furthermore, the HRSGs and will be designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations. The gas turbine and HRSG duct burner combined exhaust will achieve a CO emission limit of 6 ppmvd @ 15% O_2.

c. Dry Low-NO_x (DLN) Combustors to minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-NO_x combustors, which are designed to minimize incomplete combustion and

therefore minimize POC emissions. The HRSGs will be equipped with low-NO_x duct burners, which are also designed to minimize incomplete combustion and therefore minimize POC emissions. The gas turbine and HRSG duct burner combined exhaust will achieve a POC emission limit of 1 ppmvd @ 15% O_2.

d. Exclusive Use of Clean-burning Natural gas to Minimize SO_2 and PM_{10} Emissions

The gas turbines and HRSG duct burners will utilize exclusively natural gas as a fuel to minimize SO_2 and PM_{10} emissions. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics; the use of natural gas will result in the lowest possible emission of SO_2. PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

II Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

Table 1 is a summary of the daily maximum regulated air pollutant emissions for the gas turbines, heat recovery steam generators (HRSGs), cooling tower, emergency generator, and fire pump engine. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that will result in POC, NPOC, NO_x, SO_2, PM_{10}, or CO emissions in excess of 10 pounds per highest day per pollutant are subject to the BACT requirement for that pollutant.

Table 1: Maximum Daily Regulated Air Pollutant Emissions for Baseload Operation of Proposed Sources (lb/day)

Pollutant	Source				
	S-1 CTG & S-3 HRSG[a]	S-2 CTG & S-4 HRSG[a]	S-5 Cooling Tower	S-6 Emergency Generator[b]	S-7 Fire Pump Engine[c]
Nitrogen Oxides (as NO_2)	682	682		7.1	11.7
Carbon Monoxide	3,941	3,941		12.1	7.1
Precursor Organic Compounds	115	115		5.7	1.4
Particulate Matter (PM_{10})	228	228	17	0.024	0.38
Sulfur Dioxide	39	39		0.015	0.32

[a]Based upon one 180 minute cold start, one 60 minute hot start, 4 hours of CTG/HRSG baseload operation with HRSG firing and steam injection power augmentation and 16 hours of CTG/HRSG baseload operation in a 24-hour period.

[b]Based upon 4 hours maximum per day of non-emergency operation.

[c]Based upon 3 hours maximum per day of non-emergency operation.

Table 2 is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 5 ppmvd @ 15% O_2 due to ammonia slip from the A-1 and A-2 SCR Systems.

Table 2
Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb./yr-source)
S-1, S-2, S-3, S-4, S-5, S-6 and S-7 Combined		
Acetaldehyde[b]	2.325E+03	7.200E+01
Acrolein	2.179E+02	3.900E+00
Ammonia[c]	2.246E+05	1.930E+04
Benzene[b]	4.609E+02	6.700E+00
1,3-Butadiene[b]	4.300E+00	1.100E+00
Ethylbenzene	6.062E+02	1.930E+05
Formaldehyde[b]	3.762E+03	3.300E+01
Hexane	8.770E+03	8.300E+04
Naphthalene	5.638E+01	2.700E+02
PAHs[b]	2.236E+01	4.300E-02
Propylene	2.612E+04	N/A
Propylene Oxide[b]	1.619E+03	5.200E+01
Toluene	2.405E+03	3.860E+04
Xylenes	8.839E+02	5.790E+04

[a]pursuant to BAAQMD Toxic Risk Management Policy

[b]carcinogenic compound

[c]based upon the worst-case ammonia slip of 5 ppmvd @ 15% O_2 from the A-1 and A-2 SCR systems with ammonia injection

Table 3 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of the trigger levels shown must perform modeling to assess the net air quality impact of that pollutant.

Table 3
Maximum Annual Facility Regulated
Air Pollutant Emissions Increase

Pollutant	Cumulative Increase Emissions[a,b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	134.6	40
Carbon Monoxide	584.2	100
Precursor Organic Compounds	28.5	N/A
Particulate Matter (PM_{10})	86.4	15
Sulfur Dioxide	12.2	40

[a]Includes emissions from two gas turbines, heat recovery steam generators, natural-gas-fired emergency generator, diesel-fired fire pump engine, and cooling tower.

[b]Emissions include 156 hours of cold startups, 260 hours of hot startups, 1,500 hours at 100% duct burner capacity with the balance of the time at 100% load at 60F.

[c]For a new major facility.

The sulfuric acid mist (H2SO4) emissions will be conditioned to be less than the PSD threshold of 7 tons per year. The applicant has accepted an enforceable permit condition (Number 26) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from quarterly compliance source tests. The quarterly source test will be conducted, as indicated in Condition number 33, to measure SO2, SO3, H2SO4 and ammonium sulfates. This approach is necessary because the extent of conversion in turbines of fuel sulfur to SO3, and then to H2SO4 is not well established.

III Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed RCEC will comply with those requirements.

A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed RCEC facility are Section 2-2-301; “Best Available Control Technology Requirement”, Section 2-2-302; “Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR”, and Section 2-2-404, “PSD Air Quality Analysis”.

1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations.”

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as “BACT 2”. This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and must have been demonstrated to be effective and reliable on a full-scale unit and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as “BACT 1”. BACT specifications (for both the "achieved in practice" and “technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following sections include BACT determinations by pollutant for the permitted sources of the proposed RCEC. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

a. BACT for Combustion Turbine Generators (S-1, S-3), Heat Recovery Steam Generators (S-2, S-4), and Cooling Tower (S-5)

Nitrogen Oxides (NO_x)

District BACT Guideline 89.1.6 (10/18/00), for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for NO_x

as 2.5 ppmvd @ 15% O_2 with an averaging period of one hour or 2.0 ppmvd @ 15% O_2 with an averaging period of three hours. This BACT determination was based upon the use of SCR and Low NO_x combustors or a SCONOX System. This determination is based on analysis contained in recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595), Delta Energy Center (Application # 19414), Metcalf Energy Center (Application # 27215), and Contra Costa Power Plant Unit 8 (Application #1000). The EPA has accepted this BACT determination as Federal LAER. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

There are currently two control technologies that can achieve the BACT/LAER emission specification for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour or 2.0 ppmvd @ 15% O_2, averaged over three hours: (1) selective catalytic reduction (SCR) and (2) $SCONO_x$. These are both post-combustion flue gas treatment techniques that destroy NO_x after it is formed. SCR lowers NO_x emissions by using a reducing agent (ammonia or urea) to reduce NO_x molecules to elemental nitrogen and water. The ammonia is injected into the flue gas stream upstream of a catalyst that is used to reduce the required temperature of NO_x reduction to less than 800^oF. SCR has been widely and successfully used in combustion turbine/HRSG and boiler applications for many years. The aforementioned combined cycle projects recently issued permits by the BAAQMD all use SCR technology.

$SCONO_x$ is a new pollution control technology that can achieve the same level of NO_x reduction as SCR. This system utilizes a platinum catalyst coated with potassium carbonate to reduce emissions of NO_x and CO. The system works by oxidizing CO to CO_2 and NO to NO_2 simultaneously. The CO_2 exits the stack with the flue gas while the NO_2 is absorbed onto the coated catalyst forming potassium nitrites (KNO_2) and nitrate (KNO_3). A mixture of regenerative gases is passed through the catalyst periodically in the absence of oxygen. The gases react with the nitrites and nitrates to form water and elemental nitrogen. The system uses natural gas as the basis of regenerating the catalyst and does not require the use of ammonia. Although this technology has not yet been demonstrated for this source category (and therefore cannot be imposed by the District), it is sufficiently developed to allow the District to approve an application using it.

Top-Down BACT Analysis

A "top-down" BACT analysis for NO_x has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring.

EPA has previously commented that ABB Alstom Power, the exclusive licensee for $SCONO_x$ applications, conducted "full-scale damper testing" that demonstrates that $SCONO_x$ is technically feasible for gas turbines of the size proposed for the RCEC Facility. Stone & Webster Management Consultants, Inc. of Denver Colorado was subsequently hired by ABB to conduct an independent technical review of the $SCONO_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to

the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the $SCONO_x$ system for large turbines has not been demonstrated, we do not consider $SCONO_x$ to be a viable control alternative for NO_x, capable of being imposed on an unwilling applicant.

Although District staff does not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and $SCONO_x$. The following analysis for informational purposes only. The analysis shown in Table 4 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO_x emission rate of 25 ppmvd @ 15% O_2.

Table 4 Top-Down BACT Analysis Summary for NO_x

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	Adverse Environmental Impacts	Incremental Energy Impact (MM BTU/yr)
$SCONO_x$	788	709	4,122,889	5,815	N/A[d]	No	No	122,000[e]
SCR	788	709	1,557,125	2,196	-	Yes	No	67,900[e]

[a]based upon NO_x emission rate of 25 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[b]based upon NO_x emission rate after abatement of 2.5 ppmvd @ 15% O_2, and annual firing rate of 17,436,780 MM BTU/yr

[c]"Cost Analysis for NO_x Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d]does not apply since there is no difference in emission reduction quantity between alternatives

[e]"Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in Table 4, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 4, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the

average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15 % O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.0006 and a chronic hazard index of 0.009 resulting from the ammonia slip emissions for each turbine. In accordance with the District Toxic Risk Management Policy and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The RCEC Facility will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed RCEC and found that the impact would not

be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the RCEC Facility does not justify the elimination of SCR as a control alternative. It should be noted that aqueous ammonia, proposed for this project, is far safer than anhydrous ammonia, which is a vapor at atmospheric conditions.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.5 ppmvd NO_x @ 15% O_2, averaged over one hour, during all operating modes except gas turbine start-ups and shutdowns. The applicant has proposed complying with this emission limitation through the use of dry low NO_x combustors and selective catalytic reduction (SCR) with ammonia injection. Compliance will be verified by a CEM located at the common stack for each gas turbine/HRSG power train. Neither SCR nor $SCONO_x$ will cause significant energy, economic or environmental impacts. Either would be approvable by the District. The applicant's proposed use of SCR to meet the District's BACT standard for NO_x is therefore acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of three distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with HRSG duct burner firing and steam injection power augmentation at the gas turbine combustors. Steam injection power augmentation lowers the combustor flame temperature thereby allowing an increased fuel use rate, which in turn increases gas turbine peak generating capacity during periods of high ambient temperature. However, by lowering the combustor flame temperature steam injection can increase CO production.

District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for CO as 6 ppmvd, @ 15% O_2 with an averaging period of one hour. This BACT determination was based upon the use of CO Catalyst and Dry Low NO_x combustors. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

The Crockett Cogeneration facility was permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% O_2. This established the technologically feasible/cost-effective BACT specification cited above. However, subsequent operation of the facility has shown that this emission concentration cannot be achieved under all operating modes and ambient

conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperature and high relative humidity and during peak load operation under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration is confident that the gas turbine will not exceed a CO emission concentration of 10 ppmvd @ 15% O_2 under all loads and ambient conditions with and without duct burner firing.

Crockett has not employed steam injection power augmentation during peak load/high ambient temperature situations since the resulting CO emission concentration would exceed the current emission limit of 5.9 ppmvd CO. Based upon their operating experience, they do not expect to consistently meet 10 ppmvd CO when operating in steam injection power augmentation mode. Therefore, the achieved-in-practice BACT for CO should not apply to the steam injection power augmentation mode.

The few compliance test results available are not sufficient to support the "achieved in practice" determination. Such support would require at least 6 months (and arguably 18 months) of data showing consistent compliance under the full range of operation.

EPA advised that Sacramento Power Authority (SPA) is permitted at 4.0 ppmvd CO @15% O_2, averaged over 1 hour. Per the June 1999 CARB Power Plant Siting Guidance Document, two consecutive years of source testing indicate CO concentrations vary from 0.16 to 0.62 ppmvd CO @15% O_2. In a 9/25/01 telephone conversation with Mr. Grant Chin of CARB, he stated that he had 3 or 4 source tests that show less than 1.5 ppm CO @15% O_2 concentration at the SPA site. In a follow-up telephone conversation with Mr. Chin, he advised the District that the Sacramento Municipal Utility District (SMUD) CEM data for the SPA installation over the past year show compliance with their 3 ppm NO_x limit together with very low CO concentrations (<1 ppm averaged over 24 hours). Without adequate time to analysis and review the CEM data, District staff does not believe there is sufficient justification at this time to use this to set a new lower BACT level.

The District has recently issued power plant permits with a CO emission concentration limit of 6.0 ppmvd @ 15% O_2 during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG. Because the power plants proposed this limit, it was accepted as meeting BACT 1 for CO. However, it is not considered achieved-in-practice BACT since it has not yet been demonstrated in actual operation. The 6.0 ppmvd will be considered BACT 1 "technologically feasible/cost-effective BACT" for CO emissions.

The RCEC has agreed to a CO emission limit of 6 ppmvd @ 15% O_2 that will apply to all gas turbine/HRSG operating modes except for gas turbine start-up and shutdown. This limit will apply to the firing of the turbine alone, turbine operation with HRSG duct burner firing, and steam injection power augmentation mode. The RCEC intends to comply with this BACT specification through the use of dry low-NO_x duct burners that minimize incomplete combustion. The HRSGs and will be designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations. The applicant's proposed CO level of 6 ppm therefore complies with BACT.

Precursor Organic Compounds (POCs)

District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT for POC as 2 ppmvd, @ 15% O_2 with an averaging period of one hour. This BACT determination was based upon the use of an Oxidation Catalyst or Dry Low NO_x combustors. This determination is based on recent BAAQMD permits issued for power plants. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999. The applicant has proposed to not exceed a POC stack concentration of 1 ppmvd, @ 15% O_2.

Sulfur Dioxide (SO_2)

District BACT Guideline 89.1.6 specifies BACT for SO_2 for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal SO_2 emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 0.25 grain/scf. This average corresponds to an SO_2 emission factor of 0.000693 lb./MM Btu. The natural gas sulfur content specification of 0.25 grain per 100 scf is deemed BACT for SO_2.

Particulate Matter (PM_{10})

CTG/HRSG: District BACT Guideline 89.1.6 specifies BACT for PM_{10} for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal PM_{10} emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 0.25 grain/ scf. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as sulfates.

Cooling Tower: RCEC is proposing a cooling tower with a drift rate of 0.0005 %. Based on a recent BACT determination by the San Joaquin Valley Unified APCD (Guideline 8.3.10). The District considers BACT for the cooling towers to be a drift rate of 0.0006 % which will be published in BAAQMD BACT Guideline 181.1. The proposed drift rate is therefore acceptable.

b. BACT for Natural Gas-Fired Engine (S-6) and Diesel-Fired Engine (S-7)

The engines are subject to the "BACT 2" requirements. As mentioned above, these requirements have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA. These engines are for emergency use only, with non-emergency use (generally for testing) limited to 100 and 30 hours per year, respectively for S-6 and S-7. Therefore, "BACT 1" referred to as "technologically feasible/cost-effective" would not be cost-effective for these small, limited use engines. The table below illustrates how S-6 and S-7 comply with BACT Requirements.

Table 5
BACT Determination for S-6 and S-7 Engines

Pollutant	BACT for Natural Gas Spark Ignited Engines (g/bhp-hr)	S-6 Natural Gas Engine (g/bhp-hr)	BACT for Compression Ignition IC Engines (g/bhp-hr)	S-7 Diesel Engine (g/bhp-hr)
NO_x	1.0	1.0	6.9	5.89
CO	2.75	1.7	2.75	2.75
PM_{10}	Natural Gas[1]	0.000353	0.10	0.09
POC	1.0	0.8	1.5	0.73
SO_2	n/a[2]	negligible	low sulfur fuel[3]	low sulfur fuel

[1]PM_{10} emissions are negligible when fired with natural gas due to only trace amounts of sulfur in the fuel

[2]SO_2 emissions are negligible when fired with natural gas due to only trace amounts of sulfur in the fuel

[3]Low sulfur oil is defined as oil having less than 0.05% sulfur by weight. Permit conditions will require that only low sulfur fuel be used at S-7

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x emission increases from permitted sources at facilities, which will emit 15 tons per year or more on a pollutant-specific basis. Because the RCEC facility will emit more than 50 tons per year of NO_x, offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Because RCEC will emit less than 50 tons/year of POC, offsets must be provided, by the applicant, at a ratio of 1.0 to 1.0.

It should be noted that in the case of POC and NO_x offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

Timing for Provision of Offsets

Pursuant to District Regulation 2-2-311, the applicant must provide the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, *Power Plants*, the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the power plant.

Interpollutant Offset Ratios

Pursuant to District Regulations 2-2-302 and 2-2-302.2, emission reduction credits of precursor organic compounds may be used to offset increased emissions of nitrogen oxides at a ratio of 1.15 to 1.0.

Offset Requirements by Pollutant

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the combined emissions from the proposed units at the RCEC facility is less than 50 tons per year of Precursor Organic Compounds (POCs), the POC emission increases must be offset at a ratio of 1.0 to 1.0 pursuant to District Regulation 2-2-302.

NO_x Offsets

Because the RCEC will emit greater than 50 tons per year of Nitrogen Oxides (as NO_2) from permitted sources, the applicant must provide emission reduction credits (ERCs) of NO_x at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302. Pursuant to District Regulation, 2-2-302.2, the applicant has the option to provide POC ERCs to offset the proposed NO_x emission increases at a ratio of 1.15 to 1.0.

PM_{10} Offsets

With projected PM_{10} emissions from permitted sources of less than 100 tons per year, the RCEC does not trigger the PM_{10} offset requirement of District Regulation 2-2-303.

SO_2 Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increases associated with this project since the facility SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 does allow for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The applicant has not opted to provide such emission offsets.

Current Proposed Offset Package

Table 4 summarizes the current offset obligation of the RCEC and the quantity of valid emission reduction credits (ERCs) under the control of the applicant. The emission reduction credits presented in Table 4 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, “Emissions Banking”, and were subsequently issued as a banking certificate by the BAAQMD.

As indicated, the applicant has secured sufficient valid emission reduction credits to offset the emission increases from the permitted sources proposed for the RCEC.

Table 6
Emission Reduction Credits Identified by Calpine/Bechtel as of May 29, 2001 (ton/yr)

	POC	NO_x
Valid Emission Reduction Credits	87.35[a]	95.25[b]
Permitted Source Emission Limits	28.5	134.6
Offsets Required per BAAQMD Calculations	28.5[d]	154.8[e]

[a]From Banking Certificate # 671

[b]From Banking Certificate # 728

These Banking Certificates originated from the following locations:

Certificate	Company	Location	Original Issue Date	Original Cert.
#671	PG&E	San Francisco	9/30/85	#14[*]
#728	Pacific Refining	Hercules	1/19/01	#558[**]

[*]*Certificate #14 (#671) was generated by the shutdown of Potrero Units 1&2 (Boilers S-3, S-4, S-5; B&W 500,000 pounds per hour) at the Potrero Power Plant facility.*

[**]*Certificate #558 (#728) was generated by the closure of the Pacific Refining Company in Hercules. The credits resulted from the shutdown of process heaters (S-3,4,5,6,8,9,10,12,13) and a safety flare (S-76).*

[d]Reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-302

[e]Reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302 with 95.25 tons of NO_x and 59.55 tons of POC.

95.25 tons NO_x
59.55 tons POC
154.8 tons required

3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the RCEC project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the RCEC facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for NO_2, CO, and PM_{10} or an exceedence of any applicable PSD increment. **Table 5** summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed RCEC.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

Table 7
California and National Ambient Air Quality Standards and Ambient Air Quality Levels from the Proposed Russell City Energy Center (mg/m^3)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	211	216	427	470	---

Please see Appendix E for a detailed discussion of the PSD air quality impact analysis.

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the RCEC project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the RCEC are summarized in Table 2. In accordance with the requirements of the BAAQMD Toxic Risk Management Policy (TRMP) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

Table 8 Health Risk Assessment Results

Source	Multi-pathway Carcinogenic Risk (risk in one million)	Non-carcinogenic Chronic Hazard Index	Non-carcinogenic Acute Hazard Index[a]
Gas Turbines, HRSGs, Cooling Tower, Emergency Generator, Fire Pump Engine[b]	0.4	0.02	2.7

[a]included for informational purposes only; BAAQMD TRMP does not require an assessment of acute (short-term; i.e. < 24 hour) health impacts

[b]numbers represent combined risk from all sources

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to the BAAQMD Risk Management Policy, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index attributed to the emission of non-carcinogenic air contaminants is considered to be not significant since it is less than 1.0. Therefore, the RCEC facility is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. Please see Appendix D for further detail.

C. Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation.

Regulation 2, Rule 1, Sections 301 and 302:
Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the RCEC has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1 & S-3 Gas Turbines, S-2 & S-4 Heat Recovery Steam Generators, S-5 Cooling Tower, S-6 Emergency Generator, and S-7 Fire Pump Engine.

Regulation 2, Rule 2, Section 307: Certification of Compliance

Pursuant to Regulation 2-2-307, a Certification of Compliance has been received for all major facilities owned and operated by the applicant in the state of California. However, recent preliminary source tests results at a new power plant owned and operated by the applicant indicate a possibility of non-compliance at this facility. Neither the Authority to Construct nor the PSD permit may be issued until the compliance issues are resolved and a new Certification of Compliance has been submitted by the applicant.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, this Preliminary Determination of Compliance (PDOC) serves as the APCO's preliminary decision that the proposed power plant will meet the requirements of all applicable BAAQMD, state, and federal regulations. The PDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, the PDOC will be subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407.

Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1, the RCEC will become subject to Regulation 2, Rule 6 upon initial firing of any of the gas turbines (S-1 & S-3) or HRSGs (S-2 & S-4).

Regulation 2, Rule 7: Acid Rain

The RCEC gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), RCEC must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, “commence operation” includes the start-up of the unit’s combustion chamber.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NO_x burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot

of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (CTG and HRSG Duct Burners) is 0.0025 gr./dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 2000 mg/l and corresponding maximum P_{M10} emission rate of 0.68 lb/hr, the proposed 10-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the California Energy Commission will impose conditions on construction activities that will require the use of water and/or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the two proposed CTG/HRSG power trains will each be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at the RCEC.

The use of solvents for cleaning and maintenance at the RCEC is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

Regulation 9: Inorganic Gaseous Pollutants

<u>Regulation 9, Rule 1, Sulfur Dioxide</u>

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions that would result in ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO_2 emissions in excess of 300 ppmv (dry). With maximum projected SO_2 emissions of < 1 ppmv, the gas turbines and HRSG duct burners are not expected to contribute to noncompliance with ground level SO_2 concentrations and should easily comply with section 302.

<u>Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations</u>

The proposed combustion gas turbines (each rated at 1,979.4 MM Btu/hr HHV) will comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.5 ppmvd @ 15% O_2. The HRSG duct burners will also be limited to 2.5 ppmvd and therefore comply with this regulation.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed HRSGs are exempt from Regulation 9, Rule 7, per section 110.5 since they are used to recover sensible heat from the exhaust of the proposed combustion turbines.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

The proposed S-6 natural gas-fired engine and the S-7 diesel-fired engine are expected to comply with Regulation 9-8-330 which allows emergency use for unlimited hours, and limits non-emergency use to 100 hours per year.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines and HRSGs will be limited by permit condition to NO_x emissions of 2.5 ppmvd @ 15% O_2, they are expected to comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

D. CEQA

The CEQA requirements of regulation 2-1-426 are met because the California Energy Commission (CEC) has taken the lead agency roll on this project and are responsible for the EIR, which will fulfill the CEQA requirement. The Final Staff Assessment by the CEC serves as the EIR.

IV Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb./hr and lb./MM Btu of natural gas fired) will ensure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and NO_x limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. If the CO and NO_2 CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable gas content and the differing response times of the gas monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, SO_2, and PM_{10} mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to as designed operation of each CTG/HRSG power train and the auxiliary boilers, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and oxidation catalysts fully operational. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 1 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedence of any short-term applicable ambient air quality standard.

Russell City Energy Center
Permit Conditions

Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Firing Hours:	Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments.
MM Btu:	million British thermal units
Gas Turbine Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d).
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 27(b) through 27(d) until termination of fuel flow to the Gas Turbine.
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds. Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission point P-1 (combined exhaust of S-1 Gas Turbine and S-3 HRSG duct burners) and emission point P-2 (combined exhaust of S-2 Gas Turbine and S-4 HRSG duct burners) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the RCEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.

Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
RCEC:	Russell City Energy Center

Conditions for the Commissioning Period

1. The owner/operator of the RCEC shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 and S-3 Gas Turbines and S-2 and S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 56 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-1 & S-3 Gas Turbine combustors and S-2 & S-4 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-1 and A-2 SCR Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-1 & A-2 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall comply with the NO_x and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the RCEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1 or S-3 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines and HRSGs. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) without abatement by their respective SCR System. Neither Gas Turbine (S-1 or S-3) shall be fired sooner than 28 days after the District receives the commissioning plan.

6. During the commissioning period, the owner/operator of the RCEC shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

firing hours for each gas turbine (S-1 and S-3) and each HRSG (S-2 and S-4)
fuel flow rates to each train
stack gas nitrogen oxide emission concentrations at P-1 and P-2
stack gas carbon monoxide emission concentrations P-1 and P-2
stack gas carbon dioxide concentrations P-1 and P-2

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, NO_x mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines and auxiliary boilers, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

9. The total number of firing hours of S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-2 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 25.

11. Combined pollutant mass emissions from the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1 & S-3).

NO_x (as NO_2)	7,880 pounds per calendar day	400 pounds per hour
CO	17,716 pounds per calendar day	584 pounds per hour
POC (as CH_4)	230 pounds per calendar day	
PM_{10}	456 pounds per calendar day	
SO_2	77 pounds per calendar day	

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 20. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs; S-2 & S-4)

13. The Gas Turbines (S-1 and S-3) and HRSG Duct Burners (S-2 and S-4) shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 2,179.4 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 52,306 MM Btu per calendar day. (PSD for PM_{10})

16. The combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall not exceed 34,679,108 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-2 and S-4) shall not be fired unless its associated Gas Turbine (S-1 and S-3, respectively) is in operation. (BACT for NO_x)

18. Except as provided in Condition No. 8, S-1 Gas Turbine and S-2 HRSG shall be abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-1 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

19. Except as provided in Condition No. 9, S-2 Gas Turbine and S-4 HRSG shall be abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

20. The Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO_2) at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after abatement by A-1 SCR System) shall not exceed 19.5 pounds per hour or 0.0090 lb/MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO_2) at P-2 (the combined exhaust point for the S-2 Gas Turbine and the S-4 HRSG after abatement by A-2 SCR System) shall not exceed 19.5 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

    (c) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 0.013 lb./MM Btu (HHV) of natural gas fired or 28.3 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 6 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

    (e) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-1 and A-2 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1 and A-2 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition #31. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.72 pounds per hour or 0.00125 lb/MM Btu of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1 and P-2 each shall not exceed 1.51 pounds per hour or 0.0007 lb/MM Btu of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 9 pounds per hour or 0.00455 lb/MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 12 pounds per hour or 0.00551 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 and S-3) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Cold Start-Up (lb/start-up)	Hot Start-Up (lb/start-up)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80	18
Carbon Monoxide (CO)	2,514	902	43.8
Precursor Organic Compounds (as CH_4)	48	16	5

22. The Gas Turbines (S-1 and S-3) shall not be in start-up mode simultaneously. (PSD)

23. The heat recovery steam generators (S-2 & S-4) and associated ducting shall be designed and constructed such that an oxidation catalyst can be readily installed and properly operated if deemed necessary by the APCO to insure compliance with the CO emission rate limitations of conditions 20(c) and 20(d). (BACT)

24. Total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, and S-4), including emissions generated during Gas Turbine start-ups and shutdowns shall not exceed the following limits during any calendar day:

(a)	1,364 pounds of NO_x (as NO_2) per day	(CEQA)
(b)	7,882 pounds of CO per day	(PSD)
(c)	230 pounds of POC (as CH_4) per day	(CEQA)
(d)	456 pounds of PM_{10} per day	(PSD)
(e)	78 pounds of SO_2 per day	(BACT)

25. Cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, and S-4), Cooling Tower (S-5), Emergency Generator (S-6) and Fire Pump Engine (S-7), including emissions generated during gas turbine start-ups and shutdowns shall not exceed the following limits during any consecutive twelve-month period:

(a)	134.6 tons of NO_x (as NO_2) per year	(Offsets, PSD)
(b)	584.2 tons of CO per year	(Cumulative Increase, PSD)
(c)	27.8 tons of POC (as CH_4) per year	(Offsets)
(d)	86.4 tons of PM_{10} per year	(Cumulative Increase, PSD)

(e) 12.2 tons of SO_2 per year (Cumulative Increase)

26. The sulfuric acid emissions (SAM) from P-1 and P-2 combined shall not exceed 7 tons in any consecutive four quarters. (Basis: PSD)

27. The maximum projected annual toxic air contaminant emissions (per condition 29) from the Gas Turbines and HRSGs combined (S-1, S-2, S-3, and S-4) shall not exceed the following limits:

3,726	pounds of formaldehyde per year
2,324	pounds of acetaldehyde
218	pounds of acrolein
461	pounds of benzene per year
22.4	pounds of specified polycyclic aromatic hydrocarbons (PAHs) per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

28. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 24(a), 24(b), 25(a), and 25(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-3 combined and S-2 & S-4 combined.
(b) Carbon Dioxide (CO_2) or Oxygen (O_2) concentrations, Nitrogen Oxides (NO_x) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-1 and P-2.
(c) Ammonia injection rate at A-1 and A-2 SCR Systems
(d) Steam injection rate at S-1 & S-3 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-1 & S-3 combined and S-2 & S-4 combined.

(f) Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-1 and P-2.

Applicable to emission points P-1 and P-2, the owner/operator shall record the parameters specified in conditions 28(e) and 28(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.

(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3, and S-4) combined.

(i) the average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(j) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-1, S-2, S-3, and S-4) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentrations, NO_x mass emissions (as NO_2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-1, S-2, S-3, and S-4) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

29. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 24(c) through 24(e), 25(c) through 25(e), and 26, the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), Sulfur Dioxide (SO_2) mass emissions, and sulfuric acid mist (SAM) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 28, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, SO_2, and SAM emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3, and S-4) combined.

(b) on a daily basis, the 365 day rolling average cumulative total POC, PM_{10}, SO_2, and SAM mass emissions, for all four sources (S-1, S-2, S-3, and S-4) combined.

(Offsets, PSD, Cumulative Increase)

30. To demonstrate compliance with Condition 27, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Acetaldehyde, Acrolein, Formaldehyde, Benzene, Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,679,088 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-1 & S-3 Gas Turbines and/or S-2 & S-4 Heat Recovery Steam Generators. (TRMP)

31. Within 60 days of start-up of the RCEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-1 or A-2 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

32. Within 60 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 27. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

33. Within 60 days of start-up of the RCEC and on a quarterly basis thereafter, the owner/operator shall conduct a District approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to demonstrate compliance with the SAM levels in Condition number 26. The owner/operator shall test for (as a minimum) SO2, SO3, SAM and ammonium sulfates. After acquiring one year of source test data on these

units, the owner/operator may petition the District to switch to annual source testing if test variability is low. (Basis: PSD Avoidance, SAM Periodic Monitoring)

34. Within 60 days of start-up of the RCEC and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 27. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 30 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

Acetaldehyde	≤	72 pounds/year
Acrolein	≤	3.9 pounds/year
Benzene	≤	26.8 pounds/year
Formaldehyde	≤	132 pounds/year
Specified PAHs (TRMP)	≤	0.18 pounds/year

35. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

36. The owner/operator of the RCEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

37. The owner/operator of the RCEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

38. The owner/operator of the RCEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

39. The stack height of emission points P-1 and P-2 shall each be at least 145 feet above grade level at the stack base. (PSD, TRMP)

40. The Owner/Operator of RCEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Regulation 1-501)

41. Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 28, 31, 32, 33, 34 and 48. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

42. Prior to the issuance of the BAAQMD Authority to Construct for the RCEC, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 154.8 tons/year of Nitrogen Oxides and 27.8 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2. (Offsets)

43. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of the issuance of the PSD Permit. (Regulation 2-6-404.1)

44. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the RCEC shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Regulation 2, Rule 7)

45. The RCEC shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

46. The owner/operator shall take monthly samples of the natural gas combusted at the RCEC. The samples shall be analyzed for sulfur content using District-approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. (cumulative increase)

47. The S-5 Cooling Tower shall be properly installed and maintained to minimize drift losses. The cooling tower shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 2,000 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

48. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the Metcalf Energy Center, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 46. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition 46. (PSD)

49. The S-6 Emergency Generator shall be fired exclusively on natural gas. (Toxics, Cumulative Increase).

50. The S-6 Emergency Generator shall be operated for no more than 4 hours per day and 100 hours per year for the purpose of reliability testing or in anticipation of imminent emergency conditions. Emergency conditions are: (1) Failure of a regular power supply, or (2) involuntary curtailment of a power supply (where the utility that provides regular power has been instructed by the ISO to shed firm load, or where the utility has actually shed firm load). (BACT, Cumulative Increase)

51. The S-6 Emergency Generator shall be equipped with a non-resettable totalizing counter that records hours of operation. (BACT)

52. The following monthly records shall be maintained in a District-approved log for at least 5 years and shall be made available to the District upon request: (BACT)
    a. Total number of hours of operation for S-6
    b. Fuel usage at S-6

53. The S-7 Fire Pump Engine shall be fired exclusively on diesel fuel having a sulfur content no greater than 0.05% by weight. (Toxics, Cumulative Increase)

54. The S-7 Fire Pump Engine shall be operated for no more than 3 hours per day and 30 hours per year for the purpose of reliability testing and non-emergency operation. (BACT)

55. The S-7 Fire Pump Engine shall be equipped with a non-resettable totalizing counter that records hours of operation. (BACT)

56. The following monthly records shall be maintained in a District-approved log for at least 5 years and shall be made available to the District upon request: (BACT)
    c. Total number of hours of operation for S-7
    d. Fuel usage at S-7

V Recommendation

The APCO has concluded that the proposed RCEC, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 1979.4 MMBtu/hr maximum rated capacity, natural gas fired only; Abated by A-1 Selective Catalytic Reduction (SCR) System.

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System.

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 1979.4 MMBtu/hr maximum rated capacity, natural gas fired only; Abated by A-2 Selective Catalytic Reduction (SCR) System.

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-2 Selective Catalytic Reduction (SCR) System.

S-5 Cooling Tower, Ten Cells, 135000 gallons per minute

S-6 Emergency Generator, with Caterpillar G3512-90-LE natural gas-fired engine, 660 kW, 6.44 MMBtu/hr input

S-7 Diesel Engine, Cummins 6CTA8.3-F3, 400 hp, 2.11 MMBtu/hr input

Pursuant to District Regulation 2-3-404, this document shall be subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407.

Written comments on this Preliminary Determination of Compliance should be directed to:

Ellen Garvey
Air Pollution Control Officer/Executive Officer
Bay Area Air Quality Management District
939 Ellis Street
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